<u>FINDINGS OF FACT AND DIRECTOR'S DECISION</u>

In the Matter of the Issuance of a Temporary Permit To
Public Service Company of New Hampshire, Merrimack Station
Located in Bow, New Hampshire

The New Hampshire Department of Environmental Services, Air Resources Division (DES) implements a construction permit program for new stationary sources or stationary sources making modifications. The permitting thresholds for this program are specified in New Hampshire Code of Administrative Rules, Env-A 607.01, *Specific Applicability for Temporary Permits*. Construction permits, also called "Temporary Permits" are issued for a period of 18 months. The Temporary Permit allows the facility to construct and operate a device based on terms and conditions specified in the permit. In some cases, the Temporary Permit requires certain testing to be completed in order to verify compliance with permit terms and conditions once the device is constructed and operational.

There are typically four phases in the Temporary Permit process. They are as follows:

- First, an applicant files an application to obtain a Temporary Permit. Once the application is received by DES, it undergoes an initial review to ensure that the necessary information has been submitted.

- DES then undertakes an extensive technical review. This may include, but is not limited to, facility site visits and an analysis of historical information. Once DES has completed this technical review and is confident that the application accurately reflects the facility's operations, DES develops a "draft Temporary Permit." The draft Temporary Permit contains all applicable regulatory requirements (both state and federal) that pertain to the facility. The draft Temporary Permit may also contain certain testing requirements to verify compliance with permit terms and conditions.

- Once the draft Temporary Permit is prepared, a notice is published as required by Env-A 621, *Permit Notice and Hearing Procedures: Temporary Permits and Permits to Operate*. The public, the United States Environmental Protection Agency (EPA), and any other interested parties are invited to submit comments on the draft Temporary Permit. An opportunity for a public hearing is also provided.

- After all public comments have been received and evaluated by the DES, a final determination regarding the permit is made by the Director of the Air Resources Division (Director). If the determination is favorable, the draft Temporary Permit is finalized and issued. A draft Temporary Permit may be modified as a result of comments received during the public comment period. If modified, a formal document is generated to address changes made to the draft Temporary Permit. This document is called the "Findings of Fact and Director's Decision."

Any person aggrieved by the Director's decision can file a notice of appeal within 10 days of issuance of the final Temporary Permit, with the Air Resources Council in accordance with the provisions of Env-A 621.10, *Appeals*, and Env-AC 200, *Procedural Rules*.

Background

Public Service Company of New Hampshire (PSNH) operates Merrimack Station, a fossil-fired electric generating facility in Bow, New Hampshire. The two primary electric generating units are utility boilers that combust coal to generate steam. The steam drives a turbine generator to produce electricity for sale to the utility grid.

The two utility boilers (units MK1 and MK2) primarily burn bituminous coal. The facility also operates two standby combustion turbines which burn No. 1 fuel oil or JP-4, in addition to an emergency generator which burns No. 2 fuel oil or diesel fuel and an emergency boiler which burns No. 2 fuel oil or diesel fuel.

Units MK1 and MK2 have maximum heat input ratings of 1,238 and 3,473 million British thermal units per hour (MMBtu/hr), respectively. The flue gas from these units passes through pollution control equipment, including selective catalytic reduction (SCR) systems to control NOx emissions, and electrostatic precipitators (ESP) to control particulate matter emissions.

On June 6, 2007, PSNH filed an application requesting to install and operate a flue gas desulphurization (FGD) system to reduce mercury emissions. A co-benefit of the FGD system will be significant reductions in sulfur dioxide. New Hampshire state law (RSA-125:O) requires PSNH to undertake this project and to file an application for a Temporary Permit with DES no later than June 8, 2007. Supplemental information was submitted on September 4, 2007, April 17, 2008, October 24, 2008, November 21, 2008 and December 11, 2008.

In accordance with Env-A 621, *Permit Notice and Hearing Procedures: Temporary Permits and Permits to Operate*, a notice of request for public comments and a public hearing was published in the *Concord Monitor* on December 11, 2008. The same notice was also placed in the *Union Leader* on December 12, 2008. The notice invited public comment and indicated that a public hearing for the Temporary Permit was scheduled on January 15, 2009 at the DES offices in Concord, New Hampshire. The notice also stated that any comments received during the public comment period or at the public hearing would be considered in making a final decision. The notice stated that the deadline for written comments was January 23, 2009.

During the public hearing, several citizens offered testimony and comments both supporting and opposing this Permit application. Written comments were also received by DES prior to the January 23, 2009 deadline. The applicant was provided a copy of the written comments in accordance with Env-A 621.08, *Opportunity for Response*, but did not provide a written response.

Summary of RSA 125-O

This permit application was filed for the purpose of complying with RSA 125-O, *Multiple Pollutant Reduction Program*. Some of the main requirements of RSA 125-O are summarized below.

- RSA 125-O:13 requires PSNH to install a FGD system to control mercury emissions from Merrimack Station Units MK1 and MK2 no later than July 1, 2013. It also encourages and provides incentives for PSNH to achieve mercury reductions prior to the installation of the FGD system.
- Mercury reductions achieved through the operation of the FGD system greater than 80 percent shall be sustained insofar as the proven operational capability of the system, as installed, allows (RSA 125-O:13, V).
- RSA 125-O prohibits the purchase of mercury credits or allowances to comply with the mercury reduction requirements (RSA 125-O:13-VI).
- RSA 125-O:14 and RSA 125-O:15 establish coal sampling, measurement, and emissions monitoring requirements for periods prior to and following the installation and operation of the FGD system.

Summary of Best Available Retrofit Technology (BART) Requirements under the Regional Haze Program

The Code of the Federal Regulations, 40 CFR Part 51, Subpart P (known as the Regional Haze Rule) includes provisions to improve visibility in 156 national parks and wilderness areas across the United States. These areas are known as Class I areas, two of which are located in New Hampshire—the Great Gulf Wilderness area and the Presidential Range – Dry River Wilderness area, both located in the White Mountain National Forest. The regional haze provisions require New Hampshire to develop a state implementation plan (SIP) to establish reasonable progress goals for visibility improvement and to develop a long-term strategy for meeting these goals. To help attain these goals, the Regional Haze rule requires the implementation of the Best Available Retrofit Technology (BART) at certain existing sources that began operation between 1962 and 1977. Many states may also need to develop specific emission reduction programs to attain these visibility goals.

Since this program requires planning on a region-wide basis, the United States Environmental Protection Agency (EPA) and states decided to develop regional planning organizations across the United States. New Hampshire is part of MANE-VU – the Mid-Atlantic/Northeast Visibility Union consisting of eleven mid-Atlantic and northeastern states[1], the District of Columbia and two Indian Tribes. MANE-VU conducted a study to determine which sources contribute the most to visibility impairment. MANE-VU developed a list of 167 distinct emission units that are the top contributors. Units MK1 and MK2 at PSNH Merrimack Station are on this list. Unit MK2 at Merrimack Station is also one of two New Hampshire

[1] MANE-VU state members include Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, and Vermont.

sources that is subject to BART. PSNH Newington Station Unit 1 (NT1) is also a BART-eligible source.

MANE-VU states[2] asked its member states and other states (where these top contributing electric generating units are located) to achieve a 90 percent or greater emission reduction in sulfur dioxide emissions or an alternative level of control if 90 percent is not feasible. Emissions limitations and compliance deadlines were included in the draft Temporary Permit to satisfy these emission reduction requirements included in the New Hampshire Regional Haze SIP.

<u>Comments Received and DES Response to Comments</u>

DES received several comments during the public comment period as well as at the January 15, 2009 public hearing held in Concord, NH. Comments were received in support of and in opposition to DES' preliminary decision to issue a Temporary Permit for this project. Comments were received both supporting and opposing the project that were general in nature and did not raise an issue of fact with respect to DES' preliminary decision to issue a Temporary Permit. For this reason, DES will not specifically address each of these comments.

DES also received several comments that were specific to the draft Temporary Permit. These comments have been grouped into the following areas:

1. Comments on Project Related to Public Health;
2. General Comments Regarding Project Cost;
3. Comments Regarding Federal New Source Review Program Requirements;
4. Comments Regarding Applicability of Federal New Source Performance Standards (NSPS) and Maximum Achievable Control Technology (MACT) Requirements;
5. Comments Regarding Future State and/or Federal Rules;
6. Comments Regarding Proposed Sulfur Dioxide Emission Limits and Regional Haze Requirements;
7. Comments Regarding Alternative Operating Scenarios;
8. Comments Regarding Procedural Issues on DES' Review of the Permit Application; and
9. Comments Related to Title V Permit.

[2] On June 20, 2007, MANE-VU adopted the MANE-VU "Ask" in the "Statement of Mid-Atlantic/Northeast Visibility Union (MANE-VU) Concerning a Course of Action within MANE-VU toward Assuring Reasonable Progress" and the "Statement of the Mid-Atlantic/Northeast Visibility Union (MANE-VU) Concerning a Request for a Course of Action by States outside of MANE-VU towards Assuring Reasonable Progress."

1. Comments on Project Related to Public Health

Many public comments received at the public hearing, as well as written comments received during the public comment period, expressed concern over the potential health impacts on local residents resulting from emissions of air pollutants from the Merrimack Station facility. Comments can be grouped into two main categories. Some commenters took the position that even with the required mercury and sulfur dioxide reductions, this facility will still emit unacceptable levels of air pollution, and the Temporary Permit should be denied, or (as expressed in some of these comments) that DES should require the close of the facility altogether.

Others shared the above commenters' concern to the extent that they believe Merrimack Station currently emits unacceptable levels of air pollution. However, this group of commenters urged DES to issue the Temporary Permit so that the required mercury and sulfur dioxide reductions can occur as soon as possible, recognizing the legal requirements of the applicant under RSA 125-O.

<u>DES Response</u>:

DES recognizes the above public health concerns expressed by the commenters and notes that DES has received these types of concerns prior to this permit application. In fact, RSA 125-O:11-18 was passed in 2006 to directly address these types of concerns. DES has also undertaken other efforts in past years to evaluate and establish strategies to minimize the air quality and public health impacts from Merrimack Station. The most recent example is DES' establishment of Interim Rules Env-A 4600, *CO_2 Budget Trading Program* and Env-A 4800, *CO_2 Allowance Auction Program* to address carbon dioxide emissions from Merrimack Station.

On March 8, 2007, the Department's Environmental Health Program released a Public Health Assessment of ambient air quality in Suncook Village, which is located less than one mile from Merrimack Station. This study was undertaken to examine ambient air quality impacts, as well as available statewide health data to ascertain whether significant health disparities exist in the Suncook Village area that can be attributed to the Merrimack Station facility[3].

While the overall conclusion of the current report is that ambient air in Suncook Village does not present a health hazard to the general population, mercury, sulfur dioxide and particulate matter were identified as pollutants where additional control would further improve ambient air quality, particularly at the local level. As mentioned above, RSA 125-O was enacted to make these exact types of reductions, and the permit application for the FGD system was filed in accordance with the law requiring these air quality improvements.

Public health concerns are also addressed through another component of the permit application review process. As part of the Temporary Permit application, the applicant was required to undertake an ambient air quality impact analysis as prescribed under state and federal rules. The purpose of the analysis was to ensure that the proposed project will not result in any

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[3] This study (Suncook Ambient Air Quality Public Health Assessment) can be found on the DES website at http://des.nh.gov/organization/divisions/air/pehb/ehs/ehp/categories/publications.htm.

exceedence of the primary and secondary national ambient air quality standards (known as NAAQS) as established in federal regulation and specified under Env-A 300, *Ambient Air Quality Standards*. Env-A 300 defines "Primary ambient air quality standard" as "the level of air quality designated by the administrator of the EPA which is judged as necessary to protect the public health. For purposes of this definition, "public health" means the overall health and safety of the general human population at large." "Secondary ambient air quality standard" is defined as "the level of air quality designated by the administrator of EPA which is judged as necessary to protect the public welfare from any known or anticipated adverse effects of a pollutant. For purposes of this definition, "public welfare" means the well-being of animals and vegetation and the maintenance of property."

To the extent that a toxic air pollutant is regulated under Env-A 1400, *Regulated Toxic Air Pollutants*, the applicant must also must demonstrate compliance with the applicable ambient air limit (AAL) established for each regulated pollutant using one of the methods in Env-A 1405: 1) air dispersion modeling analysis; 2) de minimis emission level method; or 3) in-stack concentration method. The AALs were established to be protective of public health, and stationary sources must demonstrate compliance with an applicable AAL beyond its property boundary.

As part of the application for the FGD project, the applicant conducted the required ambient air quality impact analyses. The details of these analyses are contained in the document entitled "*Air Quality Modeling Report"* submitted by the applicant in November 2008. This report is part of the public record and was posted on the DES website at the start of the public comment period.

DES conducted a detailed technical review of these analyses and confirmed the applicant's conclusion that no exceedences of the NAAQS or AALs are predicted to occur, even under "worst case" operating scenarios. DES' evaluation of the analyses is contained in the DES application review summary document regarding this application.

In conclusion, DES determined that the application adequately addresses concerns related to public health impacts to the extent that they are regulated under state and federal laws and regulations. Further, no factual information was provided during the comment period which contradicts the applicant's analysis or DES' evaluation of the information provided that this project will comply with applicable health and welfare-based ambient air quality standards.

2. General Comments Regarding Project Cost

DES received a number of comments regarding the cost of the proposed installation of the FGD system and its associated components. Specifically, many commenters asked DES to ensure that PSNH explain the increased cost of installing the scrubber prior to issuance of a construction permit, as the commenters believed that such information is necessary to comply with the Clean Air Act.

As an administrative agency, DES is authorized to issue construction permits under state and federal air pollution statues and promulgated rules. The purpose of the construction permit program is to authorize the construction, installation and operation of devices subject to permit requirements. A permit issued by DES must ensure that a device, as designed, will operate in compliance with all applicable regulations and will contain sufficient monitoring, performance testing, recordkeeping and reporting requirements to ensure compliance. In this context, cost is not a permitting consideration.

With respect to comments regarding the cost or subsequent increased cost of the FGD project, DES notes that there is no applicable requirement either in state or federal statute or promulgated rule relating to NSR or PSD[4] as it applies to this permit proceeding. Furthermore, in relation to the cost of this project, RSA 125-O:11, *Statement of Purpose and Findings* states:

> "The installation of scrubber technology will not only reduce mercury emissions significantly but will do so without jeopardizing electric reliability and with reasonable costs to consumers." (RSA 125-O:11-V)
>
> The installation of such technology is in the public interest of the citizens of New Hampshire and the customers of the affected sources." (RSA 125-O:11-VI)
>
> "The mercury reduction requirements set forth in this subdivision represent a careful, thoughtful balancing of cost, benefits, and technological feasibility and therefore the requirements shall be viewed as an integrated strategy of non-severable components." (RSA 125-O:11-VIII)

Accordingly, DES is not required nor authorized to perform a prudency review regarding this issue in this permit proceeding.

Some commenters also expressed concerns that the applicant has not provided enough information about its construction plans to ensure that the scrubber will comply with environmental requirements. The draft permit establishes limits based on applicable requirements, in particular RSA 125-O, and contains sufficient applicable monitoring, performance testing, recordkeeping and reporting requirements to ensure compliance with all applicable state and federal statutes and regulations. Furthermore, DES did not receive any substantive comments which noted deficiencies with the monitoring, performance testing, recordkeeping and reporting requirements in the proposed Temporary Permit in terms of ensuring compliance with applicable state and federal statutes and regulations.

DES also received several comments urging DES (and in some cases, state government in general) to delay the issuance of this permit, as the commenters argued that the funds allocated for this project could be put to better use elsewhere, such as the development of other sources of energy and implementation of energy efficiency programs. These issues are outside DES' authority in regard to this application. DES' role in this project is to review the application to ensure that the proposed project will be able to comply with all currently applicable air quality

4 Note that the BART determination requires DES to consider the cost of compliance among other factors when determining the appropriate control level for BART. DES conducted the BART determination as part the Regional Haze SIP.

statutes and regulations, and if warranted, to issue a permit authorizing the installation of the proposed devices.

Further, Env-A 621.09, *Decisions*, requires DES to either issue or deny a permit within 30 working days of the close of the comment period following a public hearing. The comment period ended on January 23, 2009, so DES is required to make a final determination on the issuance or denial of this permit no later than March 9, 2009. By state regulation, DES cannot further delay taking a final action on this application.

3. Comments Regarding Federal New Source Review Program Requirements

DES received several comments regarding recent and future physical changes at Merrimack Station to fulfill the requirements of RSA 125-O. Many comments raise issues as to whether the physical changes are considered modifications under the federal New Source Review program as codified under the Code of Federal Regulations, 40 CFR Parts 51.165 and 52.21. These comments are noted below, along with DES' response.

The Federal New Source Review (NSR) Program consists of two main sets of regulations. Nonattainment New Source Review requirements apply to pollutants in designated "nonattainment areas" where pollutant concentrations exceed a National Ambient Air Quality Standard. Portions of New Hampshire (including Merrimack County) are designated as nonattainment areas for ozone, so the ozone precursor pollutants nitrogen oxides and volatile organic compounds are regulated under the Nonattainment New Source Review program. The Prevention of Significant Deterioration (PSD) program applies to pollutants in designated "attainment areas" where pollutant concentrations are below the respective National Ambient Air Quality Standards. New Hampshire is in attainment for all criteria pollutants other than ozone; thus the PSD requirements apply to all other criteria pollutants except ozone and its precursors, volatile organic compounds and nitrogen oxides.

For purposes of this document, the two programs will be collectively referred to as NSR, as the issues raised by the commenters apply in the same manner to both programs.

Although NSR is a federal program, New Hampshire has a federally approved NSR program, and DES is therefore responsible for implementing NSR program requirements. DES' authority includes making applicability determinations, reviewing permit applications, and making preliminary and final determinations to issue or deny a permit.

Comments were received stating that recent changes at the facility require permitting in accordance with federal NSR program requirements. Specifically, comments were submitted stating that the applicant should have obtained a NSR permit prior to making modifications to the steam turbine serving Unit MK2 in April 2008. The comments are summarized below, along with DES' response.

<u>Note</u>: The comments below refer to several provisions of the NSR regulations, including the "WEPCO Rule" as contained in 40 CFR 51.165 and 40 CFR 52.21. The WEPCO Rule provisions are a subset of the NSR regulations that address how certain changes made at electric utility generating units are to be treated with respect to NSR permitting. Due to the various types

of changes that can occur at electric generating units, the WEPCO Rule does not address how every specific type of change shall be treated with respect to permitting under NSR. For this reason, permitting authorities must often perform a case-by-case review of how the NSR regulations (particularly the WEPCO Rule) apply to the specific changes being made. Any case-specific determination that is made should be consistent with the NSR principles set forth in the NSR regulations and contained in relevant EPA guidance.

A more detailed discussion of the NSR regulations (including the WEPCO Rule provisions) as they apply to this project are detailed further in DES' responses to comments below.

<u>Comment</u>:

Commenters claim that the Unit MK2 turbine modifications were necessary to address anticipated FGD system power consumption requirements (parasitic load) and that this project should have been aggregated with the proposed FGD installation to determine whether NSR requirements are applicable. The commenters state that NSR requires that these types of "interrelated" activities must be "grouped together and considered a single project for the purpose of the NSR applicability test." The general concern expressed is that if "these sorts of activities are evaluated separately, they may circumvent the purpose of the NSR program, which is designed to address emissions from projects that have a significant net emissions increase.[5]"

<u>DES Response</u>:

DES agrees that the turbine modifications were made to address the increased power consumption requirements of the FGD system, although it should be noted that the modifications are not necessary to operate the FGD system from a technical standpoint. DES also agrees with the commenters that the turbine modifications were non-routine in nature and are therefore not covered under the NSR exemption that typically applies to routine replacement, repair, or maintenance projects. However, DES disagrees with the commenters' position that these modifications necessarily require preconstruction permitting for purposes of complying with NSR. DES also disagrees with comments stating that the turbine modifications were required to be aggregated with the FGD system installation, as explained below.

The federal NSR regulations generally address how physical changes should be treated in terms of permitting but are not always clear in how every type of modification should be addressed. For this reason, EPA has established an NSR Policy & Guidance database to assist permitting agencies making NSR applicability determinations for various situations that are not explicitly prescribed in the regulations. This database contains hundreds of past applicability determinations and court decisions that were made with respect to the NSR regulations. Ideally, the agency will review guidance on a similar situation to the case in question and apply this guidance in making an applicability determination. While helpful, it is common to find that the case in question is unique, and no comparable guidance can be found.

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5 From comments submitted by Appalachian Mountain Club, Conservation Law Foundation, Environment New Hampshire, and Union of Concerned Scientists, received on January 23, 2009.

DES reviewed this database and other relevant guidance. Based on EPA's guidance, aggregation addresses whether multiple projects that occur over a given period of time must be considered a single project for NSR purposes. EPA's position on aggregation is not clearly spelled out in the rules due to the case-specific nature of these determinations, but has instead developed over time through guidance. DES notes that EPA recently attempted to clarify aggregation issues through rulemaking[6] but did not ultimately adopt the proposed amended regulatory text into the NSR regulations. In their decision, EPA explained its rationale to not adopt the amended regulatory text:

> "We agree with many of the commenters that the proposed definitions for economic and technical dependence/viability were overly prescriptive, and we also agree that the decision to aggregate activities is highly case-specific and requires consideration of factors that are difficult to fully characterize with a bright-line test. We recognize the challenges to precisely describe these terms, particularly when the definitions must apply to the myriad cases that permitting authorities encounter."
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> "We have concluded, upon considering the comments, that the terms ''dependence'' and ''viability,'' though used by EPA in past guidance memoranda, should not be adopted as regulatory ''bright lines'' regarding whether to aggregate activities under the NSR program. Although we are not adopting regulatory language, we do note that whether a physical or operational change is dependent on another for its viability is still a relevant factor in assessing whether the changes should be aggregated. Technical or economic dependence may be evidence of a substantial relationship between changes, though projects may also be substantially related where there is not a strict dependence of one on the other."

The above statements are consistent with past EPA guidance on aggregation which suggests that permitting agencies consider the technical and economical dependency of the two projects to make an applicability determination. The timing of the individual projects is also a consideration in this decision, but EPA guidance cautions against using this as a "bright line" factor as well.

The application for the FGD system and the January 31, 2008 justification for the Unit MK2 turbine modifications were submitted within eight months of each other, i.e., within a short period of time, which could be considered as a factor for the two projects to be considered a single aggregated project. However, both projects are technically independent of each other because each of the projects is not technically limited in the absence of the other project, i.e., the Unit MK2 turbine modifications are not required to operate the FGD system.

Regarding economic dependence in this particular case, DES determined that no bright line exists. As noted by commenters, the applicant stated the purpose for the April 2008 turbine modifications was to address the increased power consumption requirements of the FGD system. This statement, absent any other factors, would tend to point toward a determination of economic dependence. However, the turbine modifications are not necessary for Unit MK2 to achieve the operational level that justifies the financial investment of the larger project (i.e., the FGD system). The FGD project is required by law and the applicant is authorized to recover the costs

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6 The final rule on aggregation was published in the Federal Register on January 15, 2009 but the effective date has been stayed for reconsideration until May 18, 2009.

of the FGD system. The modification to maintain the original net electrical output of Unit MK2 is optional, in that Unit MK2 would still be economical to operate without the turbine modifications. Likewise, if the source increased the net electrical output to simply increase the profitability of the plant, or if the FGD project did not go forward after the Unit MK2 turbine modifications were made, the modifications would have been economical on their own merits. For these reasons, DES concluded that the two projects are not strictly dependent on each other and should not be aggregated for purposes of determining NSR applicability.

Lastly, and most importantly, DES notes that if the two projects were aggregated, the applicant would have been able to take credit for the emissions reductions associated with the FGD system, thereby making it easier for the source to potentially "net out" of NSR permitting requirements for the non-routine changes that were made on Unit MK2. This approach would defeat the purpose of the aggregation provisions, which are intended to prevent sources from circumventing NSR program requirements. In this regard, the decision not to aggregate the two projects results in a *more* stringent application of the NSR regulations.

Comment:

Comments were submitted on the issue of whether the applicant should have obtained a NSR permit prior to the April 2008 Unit MK2 turbine modifications, because the applicant's post-change emission projections[7] showed a significant emissions increase above baseline (pre-change) actual emission levels. Related comments were also received questioning the pre and post-change emission levels that were provided by the applicant in its January 31, 2008 demonstration that NSR permitting did not apply to the turbine work. [One comment implied that the Clean Air Act requires a permit for all non-routine modifications at major NSR sources].

DES Response:

As discussed previously, non-routine modifications at fossil-fired electric generating plants greater than 25 megawatts in size are governed by the WEPCO Rule. The WEPCO rule allows a source making a non-routine change that could affect emissions at an electric utility steam generating unit to lawfully avoid the NSR permitting process if it can demonstrate that the post-change actual emissions do not increase by a "significant" amount over pre-change actual emissions, as defined in the NSR regulations.

Under the WEPCO rule, prior to making a non-routine change, the facility must calculate baseline (pre-change) actual emissions and must project the future actual emissions from the modified unit for the 2-year period after the physical change. Another 2-year period that is more representative of normal operation in the unit's modified state may also be considered.

In addition, the facility must maintain and submit information to the permitting agency (for a period of at least five years) demonstrating that the change did not result in a significant emissions increase. The annual reporting of emissions (which is already required under existing

[7] Citing correspondence from Mr. William Smagula of PSNH to Robert Scott, Director of the DES Air Resources Division regarding Unit MK2 turbine project dated January 31, 2008.

air permits) may last for up to 10 years if such a period is more representative of the modified unit's normal post-change operations.

When making a projection of post-change emissions, the facility does not have to include that portion of the unit's emissions which could have been accommodated before the change and is unrelated to the change, such as demand growth. This provision of the WEPCO Rule is one of many that apply to the determination of the pre and post-change emissions, depending on a number of case-specific factors regarding each modification.

By letter dated January 31, 2008, the applicant submitted a description of the proposed work to the Unit MK2 turbine, which included a demonstration that post-change actual emissions would not increase by a significant amount over the pre-change baseline emissions.

In making a comparison of pre-change to post-change actual emissions, the NSR regulations prescribe how to determine pre-change and post-change actual emissions. In general, when determining the pre-change emissions baseline, actual emissions shall equal the average rate, in tons per year, at which the unit actually emitted the pollutant during a two-year period which precedes the particular date (of the change) and which is representative of normal source operation. The permitting agencies shall allow the use of a different time period upon a determination that it is more representative of normal source operation.

In its January 2008 demonstration, the applicant provided the following calculation of actual emissions for the previous two-year period (January 2006 to December 2007) for Unit MK2:

Table 1: Actual Pollutant Emissions (in Tons per Year) for Unit MK2					
Year	Sulfur Dioxide (SO_2)	Nitrogen Oxides (NOx)	Carbon Monoxide (CO)	Particulate Matter (PM)	Volatile Organic Compounds (VOC)
2006	22,729	3,304	236	256	52
2007	25,062	2,250	228	249	50
2- year average	23,896	2,777	232	253	51

A comment was received which notes that the actual emissions listed above did not in all cases match the 2006-07 actual emissions as stated in the permit application. While this changes the values slightly and does not change the ultimate outcome of the demonstration (as discussed below), the commenter is correct. A corrected calculation using the 2006-07 actual emissions listed in the application is provided in Table 2, below (corrected numbers in bold).

Table 2: (Corrected) Actual Pollutant Emissions (in Tons per Year) for Unit MK2					
Year	Sulfur Dioxide (SO_2)	Nitrogen Oxides (NOx)	Carbon Monoxide (CO)	Particulate Matter (PM)	Volatile Organic Compounds (VOC)
2006	**22,728**	3,304	**234**	**260**	52
2007	**25,064**	**2,248**	228	**265**	50
2- year average	23,896	**2,776**	**231**	**263**	51

In the January 31, 2008 submittal, the applicant also provided its projected actual emissions for the two-year period following the change, as listed in Table 3 below.

Table 3: Projected Actual Pollutant Emissions (in Tons per Year) for Unit MK2					
Year	Sulfur Dioxide (SO_2)	Nitrogen Oxides (NOx)	Carbon Monoxide (CO)	Particulate Matter (PM)	Volatile Organic Compounds (VOC)
2008	21,742	2,918	218	238	48
2009	25,062	3,304	236	256	52

A comparison of the 2006-07 actual emissions to projected actual emissions for 2009 is provided in Table 4, below.

Table 4: Comparison of Pre-Change and Projected Actual Pollutant Emissions (in Tons per Year)					
Year	Sulfur Dioxide (SO_2)	Nitrogen Oxides (NOx)	Carbon Monoxide (CO)	Particulate Matter (PM)	Volatile Organic Compounds (VOC)
Projected Actual Emissions (2009)	25,062	3,304	236	256	52
Pre-Change (Baseline) Actual Emissions (Corrected 2006-07 avg.)	23,896	2,776	231	263	51
Post-change emissions increase/(decrease)	1,166	528	5	(-7)	1

Based on Table 4 above, it appears that SO_2 and NOx emissions following the change (i.e., the Unit MK2 turbine work) would increase by a significant amount and therefore make the proposed modification subject to NSR permitting. This was pointed out in some of the comments that DES received. However, certain types of emissions are excluded from the calculation of projected actual emissions. While the January 31, 2008 submittal could have been clearer in explaining this, the applicant made the case that the projected emissions increases can be excluded under the definition of "representative actual annual emissions" (same as post-change actual emissions) as contained in the NSR regulations. This is a complicated section of the NSR regulations and warrants further clarification, which is provided below.

The NSR regulations (in 40 CFR 51.165 and 40 CFR 52.21) define the term "representative actual annual emissions." The definition states that in determining the representative actual emissions, the permitting authority "shall exclude, in calculating any increase in emissions that results from the particular physical change or change in the method of operation at an electric utility steam generating unit, that portion of the unit's emissions following the change that could have been accommodated during the representative baseline period and is attributable to an increase in projected capacity utilization at the unit that is unrelated to the particular change, including any increased utilization due to the rate of electricity demand growth for the utility system as a whole."

This language acknowledges that not all emissions increases that occur after a change necessarily result from the change. Emissions may increase after the change for other unrelated reasons, such as increased output resulting from an increased electrical demand on the utility system as a whole, frequency of unit outages, and small variations in the fuel characteristics (for example, a small variation in the sulfur content of coal could result in an emissions increase in SO_2, even if the quantity of fuel burned and capacity utilization of the emissions unit does not increase).

Conversely, if the operation of an emissions unit to meet a particular level of demand could have been accomplished during the representative baseline period, but it can be shown that the increase is related to the changes made to the unit, then the emissions increases resulting from the increased operation must be attributed to the modification project, and cannot be subtracted from the projection of post-change actual emissions.

For these reasons, permitting authorities often look at the capacity utilization prior to and after the change as a method to determine if any emissions increases were related to the change and whether the change should require a NSR permit.

In the January 31, 2008 submittal, the applicant stated its intent to exclude the unrelated post change emissions increases listed in Table 4 above, noting that the representative actual emissions for 2009 could have been accommodated during the baseline period and are unrelated to the change, i.e., the April 2008 Unit MK2 turbine work. However, the applicant interpreted the phrase "could have been accommodated" in such a manner as to state that prior to the April 2008 turbine work, Unit MK2 could have accommodated emissions up to the enforceable limits contained in the existing permit for Unit MK2. This approach results in a demonstration that, unless post-change emissions exceed the currently permitted limits, essentially no changes will trigger NSR permitting.

DES determined that the applicant's interpretation goes beyond the intent of the NSR regulations and is not appropriate in the context of this particular facility. If DES were reviewing a similar project where the emissions unit was only a few years old, then DES may have agreed that the unit was capable of accommodating emissions up to the permitted limits.

However, given the age and historical operating capacity factor of Unit MK-2, DES determined that excluding emissions up to the currently permitted limits is not allowed.

Notwithstanding the above, DES took a more stringent view of emissions that "could have been accommodated during the representative baseline period and are not related to the change." In the January 31, 2008 submittal, the applicant provided a projection of 2009 (representative actual annual) emissions from Unit MK2. Table 5 lists the projected emissions along with the two baseline years preceding the change (2006-07).

Table 5: Comparison of Pre-Change and Projected Actual Pollutant Emissions for Unit MK2 (in Tons per Year)						
Year	Capacity Factor (%)	Sulfur Dioxide (SO_2)	Nitrogen Oxides (NOx)	Carbon Monoxide (CO)	Particulate Matter (PM)	Volatile Organic Compounds (VOC)
Annual Emissions – 2006 (Corrected Values)	**83.90**	22,728	**3,304**	**234**	**260**	**52**
Annual Emissions – 2007 (Corrected Values)	82.90	**25,064**	2,248	228	265	50
Projected Annual Emissions - 2009	83.90	25,062	3,304	236	256	52

Note that the values in bold text match the values projected for 2009[8]. Concerns were expressed by commenters that if the applicant projected 2009 emissions based on the same capacity factor as that experienced for 2006, it should have also used the 2006 emissions to project emissions for 2009. More specifically, the commenter stated that projected SO_2 emissions for 2009 should be 22,728 tons instead of 25,064 tons.

In the January 31, 2008 submittal, the applicant was making a case that while it did not project an increase in capacity utilization of Unit MK2 in 2009, recent operating data showed that Unit MK2 could have accommodated the higher (2007) level of SO_2 emissions, even at a lower level of capacity utilization. Further, since these emissions were achieved prior to the change, it seems reasonable to assume these emission levels are not related to the change.

Therefore, while DES did not agree entirely with the applicant's approach (as stated previously) in its January 31, 2008 justification, it determined that the applicants' projection of 2009 emissions is justifiable. DES will continue to review post-change emissions. If DES believes that emissions have increased as a result of the changes made to the Unit MK2 turbine, then it will take appropriate actions to ensure compliance with the NSR regulations.

8 As mentioned earlier in this document, the SO_2, CO, and PM emissions highlighted in bold do not exactly match the 2009 values due to an error in the January 31, 2008 submittal.

Comment:

Comments were received stating that costs for the modifications made to Unit MK2 in April 2008 should have been provided to DES to ensure compliance with Clean Air Act requirements.

DES Response:

With regard to the NSR regulations, the cost of the project is only relevant in determining whether a project is routine or non-routine. In the case of the Unit MK2 turbine work, DES determined that the work is non-routine. No commenters dispute DES' position that the Unit MK2 turbine work was non-routine in nature, therefore detailed cost information for this work was not relevant for purposes of determining NSR applicability.

Comment:

A comment was received questioning the "baseline years" used by the applicant to determine the actual emissions prior to the April 2008 work on the Unit MK2 turbine. This is based on the commenter's assertion that the turbine work and FGD system should be aggregated as a single project to determine NSR applicability. The comment notes that RSA 125-O:13 required the preconstruction permit application to be filed by June 8, 2007 (it was filed June 6, 2007), and therefore necessitated the use of baseline years preceding 2007.

DES Response:

As detailed in the response to comments related to project aggregation, DES disagrees that the two projects should be aggregated to determine NSR applicability. For this reason, and since the turbine work was conducted in 2008, DES believes that the applicant correctly used 2006-07 as the baseline years in its January 31, 2008 determination on whether the turbine work was subject to NSR permitting.

4. Comments Regarding Applicability of Federal New Source Performance Standards (NSPS) and Maximum Achievable Control Technology (MACT) Requirements

DES received comments regarding recent and future physical changes at Merrimack Station. These comments raise issues as to whether the physical changes constitute "reconstruction" or a "modification" under two federal regulatory programs: Standards of Performance for New Stationary Sources NSPS as codified in 40 CFR Part 60, and Maximum Achievable Control Technology (MACT) Standards as codified under 40 CFR Part 63. These comments are detailed below, along with DES' response.

Comment:

A comment was received regarding physical changes that will be necessary to accommodate the installation of the FGD system and associated exhaust stack. In particular, the commenter states:

> "The installation of the scrubber [FGD system] and new stack, and the various alternative operating scenarios will require physical changes to the plant in order to modify the mechanical draft, most likely through higher capacity induced draft fans to remove flue gas from the boiler and force the exhaust gases up the stack to be emitted. Any such physical changes will change the maximum emissions rates for regulated pollutants including HAPs [hazardous air pollutants] regulated under the Clean Air Act. The draft permit is deficient because it does not provide the emissions rates for regulated pollutants, including HAPs, that the source is capable of achieving prior to the change, and does not provide post-change emissions rates for regulated pollutants including HAPs. The draft permit fails to assess whether the proposed change will result in the applicability of New Source Performance Standards pursuant to 40 CFR Part 60 (e.g., if any of the allegedly proposed alternative operating scenarios would constitute a "modification"), or will constitute a modification under Section 112(g) of the Clean Air Act requiring case-by-case MACT."

DES Response:

This comment questions whether some of the proposed plant changes, in particular the installation of higher capacity induced draft fans, is considered as a "modification" as defined under the NSPS and MACT standards under Sections 111 and 112 of the Clean Air Act, respectively. Changes that are defined as a modification typically require a source to comply with a NSPS or MACT standard that was previously not applicable.

There are important differences in the two NSPS and MACT definitions. The NSPS definition applies only to pollutants that are regulated under a NSPS standard, including particulate matter, sulfur dioxide, carbon monoxide, and nitrogen oxides. The MACT definition applies only to HAPs that are regulated under Section 112(b) of the Clean Air Act. The two programs have some similarities regarding modifications but also have important differences. DES addresses these issues separately below.

DES Response on NSPS Comments Regarding Modification:

Section 111(a)(4) of the Clean Air Act (for NSPS) defines a modification as "any physical change in, or change in the method of operation of, an existing facility which increases the amount of any air pollutant (to which a standard applies) emitted into the atmosphere by that facility or which results in the emission of any air pollutant (to which a standard applies) into the atmosphere not previously emitted". The NSPS general provisions (40 CFR § 60.14, *Modification*) further clarify the types of activities that are not considered as NSPS modifications:

> "The addition or use of any system or device whose primary function is the reduction of air pollutants, except when an emission control system is removed or is replaced by a system which the Administrator determines to be less environmentally beneficial."

This provision is specifically intended to exempt pollution control systems that are installed for the purpose of reducing pollutants. Since RSA 125-O requires the installation of the FGD system to reduce air pollutants, specifically mercury (not a NSPS regulated pollutant) and sulfur dioxide (a NSPS regulated pollutant), the FGD system does not trigger the NSPS as a modification.

In addition, DES agrees with the applicant that the FGD system and associated equipment will not increase the maximum hourly emission rates of NSPS regulated pollutants. While the commenter makes the presumption that emissions will increase from the changes (e.g., installation of induced draft fans), no supporting information was provided to contradict the applicant's claim (of no hourly emissions increase, the test used under the NSPS).

Changes to a steam generating unit, including changes that may affect the air balancing of the unit, are not necessarily modifications under the NSPS because they do not always increase the maximum emissions rate. DES cites a 2003 EPA applicability determination[9] where substantial changes were made to a boiler, including the replacement of an existing tangential overfire air system with an "opposed wall" system. DES has determined that these changes to the combustion system are at least as substantial as the changes necessary to accommodate the FGD system in terms of its affect on combustion conditions (and consequently emissions). In the 2003 applicability determination, EPA states:

> "This replacement would constitute a new source performance standard (NSPS) modification as defined in 40 CFR Part 60 Subpart A Section 60.14 if it resulted in increasing emission limits, air emissions, or boiler production capacity. However, this system actually will not affect any of the emission limits nor will it increase emissions or increase the production capacity of the boiler. Replacements such as [company's] effort are exempt from NSPS requirements. In fact, because the "Opposed Wall" system injects air more uniformly across the furnace, it results in more uniform and complete combustion, enhanced control of NOx, and enhanced CO burnout. This project meets the requirements of a pollution control project as specified in EPA's guidance of Excluding Pollution Control Projects from Major New Source Review (July 1, 1994)."

Extensive EPA guidance and applicability determinations exist on how pollution control systems are to be addressed in the context of a "modification" under the NSPS. While the emission tests that determine applicability under the NSPS and NSR differ, EPA often references relevant NSR applicability determinations and policy guidance in making its determinations on pollution control systems, as they did in the above determination.

To further address the commenter's concerns regarding the installation of equipment (such as induced draft fans) to facilitate operation of the FGD system, DES reviewed the July 1, 1994 EPA guidance (referenced in the above determination) to see if there is a "bright line" where certain equipment associated with the pollution control system no longer becomes part of the "system" but rather a change to the emission unit. No such bright line exists but DES notes that the July 1994 guidance defers to the same language contained in the preamble to the WEPCO Rule and that was referenced in DES' response to NSR applicability comments:

> "…a pollution control project refers to a project undertaken at a utility unit for purposes of reducing emissions from such unit. These changes are limited to the installation of conventional or innovative emissions control equipment, including, but not limited to, installation of conventional and advanced flue gas desulfurization, sorbent injection for sulfur dioxide (SO2) and NOx controls, electrostatic precipitators, and projects undertaken to accommodate switching

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[9] NSPS Applicability Determination - Letter from Michael P. Kenyon, Chief, Air Programs Branch, Office of Ecosystem Protection to Lynn Ross, Bureau of Air Quality Control, ME DEP, dated February 28, 2002.

to a less polluting fuel, including natural gas or coal re-burning, co-firing of natural gas and other fuels for the purpose of controlling SO_2 and NOx emissions."

"Likewise, any activity that is necessary to accommodate switching to a less polluting fuel is considered to be part of the pollution control project. ***In some instances, this may involve changes to the pollution generating equipment (e.g., boiler), but only if the changes are necessary to maintain the normal operating capability of the unit at the time of the project, where the capability would otherwise be impaired as a result of the fuel switch. For example, an electric utility steam generating unit that switches from a higher sulfur bituminous coal to a low-sulfur subbituminous coal may need to make certain changes to the boiler in order to avoid derating the unit."*** **[emphasis added]**

The commenter did not dispute and appears to understand that the induced draft fans and other changes in equipment are necessary to maintain the normal operating capability of the unit at the time of the project. DES believes that the above language makes clear that EPA anticipated that these types of changes may be necessary and that the NSPS should not apply.

As a final clarification, DES does not consider the April 2008 Unit MK2 turbine work as part of the pollution control "system." While the net electrical generating output of Unit MK 2 will be reduced due to the parasitic electrical load of the FGD system components, the turbine work is not necessary to maintain normal boiler operations. This is in contrast to the replacement of the induced draft fans that are necessary to maintain normal boiler combustion conditions when the FGD system becomes operational.

The decision to conduct the turbine work was made by the applicant as a financial consideration, i.e., to offset generating capacity lost to the FGD system. The turbine work is therefore not covered under the NSPS modification exemption for pollution control systems. However, the turbine work does not affect the boiler's combustion conditions and subsequently would not result in an hourly emissions increase, the reason why it is not a NSPS modification.

DES Response on MACT Comments Regarding Modification:

Section 112(a)(5) of the Clean Air Act (for MACT) defines a modification as "any physical change in, or change in the method of operation of, a major source which increases the actual emissions of any hazardous air pollutant emitted by such source by more than a de minimis amount or which results in the emission of any hazardous air pollutant not previously emitted by more than a de minimis amount." Section 112 does not contain an exemption for the installation of pollution control systems as contained in the NSPS and NSR regulations.

The commenter correctly notes that the facility will be required to install higher capacity induced draft fans to remove flue gas from the boiler and force the exhaust gases up the stack. Higher capacity induced draft fans will indeed be necessary to make up for the increased pressure drop that will be caused by the FGD system. However, the commenter makes a presumption that this will automatically result in a change in maximum emissions rates for regulated pollutants, including HAPs.

As explained in the response to comments regarding modifications under the NSPS, DES does not agree that the types of changes noted by the commenter will increase emissions, in this case, the emissions of HAPs. No information was provided by the commenter demonstrating how emissions will in fact increase from the FGD system and associated equipment. Therefore, DES confirms its position that the installation of the FGD system is not a modification as defined under Section 112 as there is no evidence that the changes will increase HAP emissions.

Comment Regarding Reconstruction under the NSPS and MACT Standards:

A comment was submitted on whether the physical changes necessary to accommodate the FGD system installation constitute "reconstruction" as defined under the NSPS, 40 CFR §60.15, *Reconstruction* (NSPS definition) and under 40 CFR §63.2, *Definitions* (MACT definition) of the Clean Air Act. The comment is provided below:

> "…PSNH's application for a Temporary Permit does not provide its cost estimate for the proposed modification as necessary to assess whether the proposed change constitutes "reconstruction" under 40 CFR 60.15 and/or Section 112 of the Clean Air Act. In a filing to the Public Utilities Commission dated September 2, 2008, PSNH stated that the current cost estimate for the proposed change is $1,054 per kW [cost of $456,382,000] [10] installed at Merrimack Station, which is more than 50% of the capital cost that would be required to construct a comparable process or production unit. PSNH is required to provide information regarding the cost and specific elements of the proposed changes sufficient to determine whether the proposed changes constitute reconstruction. As a result, the draft Temporary Permit fails to assess and provide for compliance with applicable requirements."

DES Response:

Both the NSPS and MACT definitions of "reconstruction" are based on a 50% cost threshold, but they differ on the basis of how these costs are factored into the determination. The NSPS and MACT definitions of "reconstruction" are provided below.

> From 40 CFR 60.15(b) (NSPS definition):
>
> "Reconstruction" means the replacement of components of an existing facility to such an extent that:
>
> (1) The fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a *comparable entirely new facility [emphasis added]*, and
>
> (2) It is technologically and economically feasible to meet the applicable standards set forth in this part.
>
> From 40 CFR 63.15(b) (MACT definition):
>
> *Reconstruction,* unless otherwise defined in a relevant standard, means the replacement of components of an affected or a previously non-affected source to such an extent that:
>
> (1) The fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable new source; and

[10] The $456,382,000 figure assumes 433,000 kW (433 megawatts) multiplied by $1,054 per kW.

> (2) It is technologically and economically feasible for the reconstructed source to meet the relevant standard(s) established by the Administrator (or a State) pursuant to section 112 of the Act. Upon reconstruction, an affected source, or a stationary source that becomes an affected source, is subject to relevant standards for new sources, including compliance dates, irrespective of any change in emissions of hazardous air pollutants from that source.

As shown, the two definitions differ in how the 50 percent cost threshold is considered. Under the NSPS definition, the fixed capital cost of the new components must exceed 50 percent of the fixed capital cost that would be required *to construct a comparable entirely new facility*. This is more expansive in scope than under the MACT definition, which is based on a more narrow definition limiting the fixed capital cost *to construct a comparable new source*.

While DES believes it is important to note the differences between the NSPS and MACT definitions regarding reconstruction, DES concluded that the proposed FGD system and associated components, based on empirical assumptions alone, would not approach the 50 percent cost threshold under either the NSPS or MACT definitions of "reconstruction".

The comments regarding reconstruction under the NSPS and MACT definitions appear to rely on two broad assumptions regarding both the project cost and the components of the FGD system that are subject to the 50 percent threshold tests. First, the commenter implies that the total stated cost of the FGD project (approximately $457 million) is equal to the fixed capital cost of the "replaced components." By making this assumption, the commenter is also making a related assumption that all of the components included in the FGD project replace another component of the affected facility. Since the vast majority of the FGD system components are not *replacing* a component at the existing facility, they are not considered in the 50 percent cost threshold for purposes of NSPS and MACT applicability.

The commenter also makes a claim that $457 million is greater than 50% of the capital cost of a "comparable process or production unit" as defined under the MACT definition. However, the commenter provides no information regarding the determination of the capital cost to construct a comparable process or production unit. For purposes of this discussion, DES can reasonably assume that the commenter believes that it would cost less than $914 million to build a comparable unit, as this is the only way that the estimated $457 million cost of the FGD system could exceed the 50 percent threshold. Again, the commenter did not provide any information as to how they arrived at the maximum $914 million cost for a new unit.

In the alternative, even if DES accepted the commenter's assumption that the entire $457 million budgeted for the FGD system project was solely due to replacement components, DES maintains that this does not meet the 50 percent threshold for triggering the reconstruction definitions under the NSPS and MACT and as explained below.

As the commenter noted, the $457 million figure is based on an assumption of 433 megawatts of generation and a FGD system cost of $1,054 per kilowatt (kW) as provided by the applicant. For this to exceed the 50 percent threshold, the cost of a comparable new unit would need to be less than twice the cost quoted above, or $2,108 per kilowatt. DES researched the cost of new power plants to determine a reasonable estimate for a new emissions unit. Costs for new power plants have increased dramatically in the past few years, not only due to increased costs for raw materials such as steel but also due to other factors such as increased worldwide demand for the construction of new electric generating facilities. The increased cost of the FGD system from 2006 to 2008 (from $250 million to $457 million) is one example of the effect of increases in raw material costs in recent years. Therefore, in obtaining cost estimates, it is important to look at the most recent cost information available.

While DES reviewed several sources of information, the most recent, comprehensive information on cost is contained in a paper released by Synapse Energy Economics in July 2008[11]. The study, titled "Coal-Fired Power Plant Construction Costs" indicates that as recently as 2005, the cost to construct a new power plant typically ranged from $1,500/kW to $1,800/kW. However, in the period from 2006 to 2008, these costs rose dramatically, in many cases doubling the cost of a new plant. In evaluating several new power plant projects around the United States, the lowest cost estimate cited in the study was $2,500/kW. This was the low end of the range, with a high of $3,800/kW. The study also concludes that the current cost has "reached $3,500 per kW, without financing costs, and are still expected to increase."

In each case, the current estimates are well above the $2,108/kW cost ceiling that the commenter relied on to conclude that the capital cost of the FGD system is greater than 50 percent of the cost to construct a comparable emissions unit. Furthermore, as DES noted earlier, most of the cost of the FGD project is <u>not</u> related to replacement components, which only serves to reduce the costs that are used in the 50 percent threshold analysis as it relates to the term "reconstruction" under the NSPS and MACT definitions. For these reasons, DES determined that it was not necessary for the applicant to provide detailed cost information on replacement components to determine whether this project would constitute reconstruction as defined under the NSPS and MACT. Therefore, the draft Temporary Permit is not deficient in addressing the term reconstruction under the NSPS and MACT regulations.

5. Comments Regarding Future State and/or Federal Rules

DES received several comments regarding future state and/or federal rules and the possibility that the coal-fired units at Merrimack Station may not be able to comply with these rules. The comments were primarily directed at regulations intended to reduce mercury and carbon dioxide (CO_2) emissions.

<u>Comments on Anticipated Federal Mercury MACT Requirements and Feasibility of Activated Carbon Injection for Mercury Removal:</u>

Comments were received referencing recent court decisions[12] which vacated the EPA's Clean Air Mercury Rule and Delisting Rule for fossil-fired electric generating units (EGUs). As a result of this decision, EPA must now promulgate Section 112 (MACT) emissions standards for hazardous air pollutants, including mercury, emitted by EGUs. Several commenters predict that this MACT standard will require EGUs such as Merrimack Station (Units MK1 and MK2)

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11 The entire document can be found at http://www.synapse-energy.com.

12 *New Jersey v. EPA*, 517 F. 3d 574 (D.C. Cir. 2008), *mandate issued* (Mar. 14, 2008), *reh'g and reh'g en banc denied*, Nos. 05-1097 and consolidated cases (May 20, 2008).

to reduce mercury emissions by approximately 90-95 percent, which is more stringent than the mercury emission reduction requirements contained in RSA 125-O:13.

Many of the same commenters note that EGUs employing Activated Carbon Injection ("ACI") technology can achieve mercury removal efficiencies in excess of 90%. Testimony was provided in reference to an analysis concluding that ACI removes more mercury for less money than FGD technology. A commenter estimated that the cost of retrofitting a mid-sized coal plant with ACI would range from $1 million to $5 million in capital costs, with approximately the same amount in annual operating costs.

DES Response:

DES agrees with the commenters that ACI is a promising technology for mercury control from power plants. As this technology develops, the potential for additional mercury reductions from EGUs is likely. In fact, trial testing of ACI technology (using various proprietary forms of activated carbon) has been conducted at Merrimack Station over the past few years. DES notes that the 90-95 percent mercury reduction was not achieved at Merrimack Station during these trials.

However, the purpose of the draft Temporary Permit is to authorize the applicant to undertake construction to comply with an existing law requiring mercury control (RSA 125-O:13). RSA 125-O requires the applicant to install "scrubber technology" to control mercury emissions at Units MK1 and MK2 no later than July 13, 2013. There is no statutory or regulatory basis to include a potentially more stringent mercury limit to comply with future federal requirements that have not yet been proposed, let alone promulgated.

The FGD system should not be considered as mutually exclusive to the implementation of ACI technology. RSA 125-O does not preclude, but in fact specifically encourages the applicant to achieve additional mercury reductions through other means. The law contains specific incentives for the applicant to make additional reductions as early as possible. Further, RSA 125-O:13, V provides that mercury reductions achieved through the operation of the scrubber technology that are greater than 80 percent to be sustained insofar as the proven operational capability of the system, as installed, allows. This higher mercury reduction rate (if achieved) would become an enforceable permit limit.

If ACI technology can be employed for the ($1-5 million) cost cited by the commenter, this would support the notion that for a modest additional investment, ACI technology could be used supplement the FGD system and meet any future MACT-based mercury limit, assuming any MACT would be more stringent than the level achieved through compliance with RSA 125-O.

Finally, although the commenters state that ACI technology may be more cost effective than FGD in terms of mercury removal, the comments received only address mercury control and ignore the other air quality benefits of the FGD system. In addition to the minimum 80 percent mercury removal, FGD will reduce at least 90 percent of the SO_2 emitted from Merrimack Station Units MK1 and MK2. By removing SO_2, the FGD also reduces fine particulate matter, as SO_2 is a precursor compound for fine particulate matter. While RSA 125-O:11 specifically targets mercury reductions, RSA 125-O:11,II (*Statement of Purpose and*

Findings) states that a FGD system will achieve the additional benefits of removing SO_2, small particulate matter, and improved visibility (regional haze).

Comments on Anticipated Federal Requirements Regulating Carbon Dioxide (CO_2) Emissions:

Several comments were received raising the possibility of federal legislation that could establish new CO_2 emissions limits on Merrimack Station Units MK1 and MK2. These comments also raise questions as to whether Units MK1 and MK2 could meet a future CO_2 standard, noting that there is no current add-on control technology to reduce CO_2 emissions. In some cases, commenters requested that DES delay a decision on the issuance of the draft Temporary Permit until federal legislation is developed. The general concern expressed is that after the $457 million investment in the FGD system, that a future federal CO_2 standard may prohibit further operation of Units MK1 and MK2.

DES Response:

As noted under the above section regarding potential federal mercury standards, DES believes that these concerns are outside the scope of the permit application under consideration. DES reiterates its position that it does not have the legal authority to impose federal standards that have yet to be proposed or promulgated. Further, any federal rulemaking process will very likely take one to two years. DES is responsible for reviewing the application to ensure that the proposed project will be able to comply with all currently applicable air quality statutes and regulations, and if warranted, to issue a permit authorizing the installation of the proposed devices.

As mentioned earlier in this document, Env-A 621.09, *Decisions*, requires DES to either issue or deny a permit within 30 working days of the close of the comment period following a public hearing. DES is required to make a final determination on the issuance of this permit no later than March 9, 2009. For this reason, DES cannot further delay taking a final action on this application.

Further, it should be noted that in 2008, House Bill 1434 was passed approving New Hampshire's participation in a ten state effort, known as the Regional Greenhouse Gas Initiative (RGGI). Interim Rules Env-A 4600, *CO_2 Budget Trading Program* and Env-A 4800, *CO_2 Allowance Auction Program* were effective on October 1, 2008. RGGI is a market-based "cap and trade" program and may be the basis for the development of a future federal CO_2 control program. The following description of the RGGI program was taken from the RGGI website (www.rggi.org):

> To reduce emissions of greenhouse gases, the RGGI participating states are using a market-based cap-and-trade approach that includes:
>
> - Establishing a multi-state CO_2 emissions budget (cap) that will decrease gradually until it is 10 percent lower than at the start;
> - Requiring electric power generators to hold allowances covering their emissions of CO_2;
> - Providing a market-based emissions auction and trading system where electric power generators can buy, sell and trade CO_2 emissions allowances;

- Using the proceeds of allowance auctions to support low-carbon-intensity solutions, including energy efficiency and clean renewable energy, such as solar and wind power;
- Employing offsets (greenhouse gas emissions reduction or sequestration projects at sources beyond the electricity sector) to help companies meet their compliance obligations.

This RGGI program applies to Merrimack Station. Additional information on RGGI and New Hampshire's efforts to regulate greenhouse gases, including regulations specific to RGGI requirements for EGUs, can be found at the RGGI website listed above and from the DES website at http://des.nh.gov/organization/divisions/air/tsb/tps/climate/rggi/index.htm.

6. Comments Regarding Proposed Sulfur Dioxide Emission Limits and Regional Haze Requirements

Comments were received from EPA Region 1 regarding the proposed sulfur dioxide (SO_2) limit for Unit MK2 and how it relates to New Hampshire's State Implementation Plan (SIP) to address regional haze. While the draft Temporary Permit did not include a SO_2 limit for Unit MK1, EPA also commented on the regional haze SIP requirements as they apply to Unit MK1.

As discussed earlier, New Hampshire is required to develop a regional haze State Implementation Plan (SIP). One component of this SIP is the determination of Best Available Retrofit Technology (BART) for existing stationary sources which were placed into operation between 1962 and 1977. Merrimack Station Unit MK2 is a BART-eligible emission unit. MANE-VU formed a workgroup to determine available emission control technologies for BART. MANE-VU found that the SO_2 removal efficiency for existing wet limestone scrubber technology is usually 31 to 97 percent, with an average of 78 percent. The MANE-VU Workgroup developed draft recommendations for the MANE-VU Air Directors of presumptive levels for BART Control. The draft recommendation for presumptive BART levels for SO_2 control for electric generating units was 95 percent control or 0.15 lb SO_2/MMBtu. Note that the MANE-VU workgroup and the MANE-VU Air Directors never finalized these recommendations.

In addition to BART, the Regional Haze SIP must also identify additional control strategies to reduce visibility impairment. MANE-VU identified 167 emission units that have the greatest impact on visibility impairment in Class I areas in MANE-VU. Merrimack Station Units MK1 and MK2 are included in this list. As mentioned earlier, the MANE-VU states asked its member states and other states where these top contributing electric generating units are located to achieve a 90 percent or greater emission reduction or an alternative level, if 90 percent is infeasible.

EPA's two specific comments and DES' responses are provided below.

Comment Regarding BART for Unit MK2:

Table 4, Item No 6 of the permit states that Unit MK2 will be required to meet a 90 percent SO_2 removal rate. The MANE-VU BART workgroup recommendation for coal EGUs (such as MK2) is, however, 95 percent control of SO_2. In addition, while FGD SO_2 removal efficiencies may vary from 80 percent to greater than 99 percent, most current applications of this technology have a removal efficiency of greater than 90 percent. Therefore, DES should explain why the state is proposing a control level of 90 percent.

DES Response:

As noted above, MANE-VU found that the existing SO_2 removal efficiencies of wet limestone scrubber technology range from 31 to 97 percent, with an average of 78 percent. The MANE-VU BART workgroup recommended to the MANE-VU Air Directors draft presumptive levels of SO_2 control of 95 percent or 0.15 lb SO_2/MMBtu. The MANE-VU states, approved by the Air Directors, asked for 90 percent control or an alternative level of control if 90 percent is infeasible.

With this in mind, DES agrees with EPA that some FGD systems designed specifically for SO_2 removal should be able to achieve reductions greater than the 90 percent specified in the draft Temporary Permit. However, the FGD system design for Merrimack Station is optimized towards maximum mercury removal for the purpose of complying with RSA 125-O. Also, to demonstrate compliance with 95 percent SO_2 removal on a consistent basis, as would be required as an enforceable permit condition, in actuality the source must achieve a level of over 95 percent to account for any variability in boiler operation or minor variations in the accuracy of emissions monitoring instrumentation. For this reason, DES determined that the minimum of 95 percent SO_2 removal (as recommended by the MANE-VU BART workgroup) would not be an appropriate permit limit at this time, and instead chose the MANE-VU Director approved and agreed upon SO_2 removal efficiency of 90 percent as a minimum control level.

Notwithstanding the above, PSNH may be able to maintain some level of control above the minimum 90 percent SO_2 removal after installation of the FGD system. Further, it is in the public interest to maintain the highest level of SO_2 reduction possible, regardless of the minimum as required under a permit. Therefore, to ensure maximum achievable SO_2 reductions, DES revised the following requirements in Table 4, Item 6 of the Temporary Permit to read as follows:

a. Beginning on July 1, 2013, when MK2-PC7 (FGD system) is in operation, SO_2 emissions shall be controlled to 10 percent of the uncontrolled SO_2 emission rate (90 percent SO_2 removal). Compliance with this percent reduction shall be determined on a calendar month average by comparing the SO_2 emission rates as measured by CEMS on the inlet and outlet of the FGD system.

b. The Owner shall submit a report no later than December 31, 2014 that includes the calendar month average SO_2 emission rates at the inlet and outlet of the FGD and the corresponding calendar month average emissions reductions during the preceding 12 months of operation, excluding the initial startup and commissioning period and any periods when the FGD system is not operating. DES will use this data to establish the maximum sustainable rate of SO_2 emissions reductions for MK2. The maximum sustainable rate is the highest rate of reductions that can be achieved 100 percent of the time.

c. DES shall establish the maximum sustainable rate of SO_2 emissions reductions based on a statistical analysis of the data submitted to DES pursuant to paragraph b. above. This established rate shall be incorporated as a permit condition for MK2. Under no circumstances shall the SO_2 removal efficiency for MK2 be less than 90 percent.

The revised permit conditions will ensure that New Hampshire is meeting or going beyond its commitment to reduce SO_2 emissions by 90 percent at Units MK1 and MK2.

Comment Regarding SO_2 Emissions from Unit MK1:

Although Unit MK1 is not a BART source, it has been identified (along with Unit MK2) by MANE-VU as one of the 167 stacks with the greatest impact on a MANE-VU Class I area. The MANE-VU "ask" is 90 percent SO_2 control or an alternative control level if infeasible for the 167 stacks. Although Table 3 of the draft Temporary Permit indicates that the FGD system controls both Units MK1 and MK2, the operational and emission limitations in Table 4 do not explicitly require a 90 percent SO_2 reduction from MK1. Therefore it is not clear how DES intends to make the MANE- VU "ask" enforceable.

DES Response:

DES agrees that the draft Temporary Permit could be more specific in terms of SO_2 control requirements for Unit MK1, particularly as they relate to New Hampshire's commitment to following the MANE-VU "ask". To further clarify these control requirements for Unit MK1, DES added the following conditions/revisions to the Temporary Permit:

Table 4, Item 8:

a. Beginning on July 1, 2013, when MK2-PC7 (FGD system) is in operation, SO_2 emissions shall be controlled to 10 percent of the uncontrolled SO_2 emission rate (90 percent SO_2 removal). Compliance with this percent reduction shall be determined on a calendar month average by comparing the SO_2 emission rates as measured by CEMS on the inlet and outlet of the FGD system.

b. The Owner shall submit a report no later than December 31, 2014 that includes the calendar month average SO_2 emission rates at the inlet and outlet of the FGD and the corresponding calendar month average emissions reductions during the preceding 12 months of operation, excluding the initial startup and commissioning period and any periods when the FGD system is not operating. DES will use this data to establish the maximum sustainable rate of SO_2 emissions reductions for MK1. The maximum sustainable rate is the highest rate of reductions that can be achieved 100 percent of the time.

c. DES shall establish the maximum sustainable rate of SO_2 emissions reductions based on a statistical analysis of the data submitted to DES pursuant to paragraph b. above. This established rate shall be incorporated as a permit condition for MK1. Under no circumstances shall the SO_2 removal efficiency for MK1 be less than 90 percent.

Table 4, Item 9:

Beginning on July 1, 2013, the Owner shall not operate MK1 through STMK2 (bypass stack) if MK2-PC7 is capable of stable operation.

Table 4, Item 10:

Beginning on July 1, 2013, the Owner shall not operate MK1 through STMK2 (bypass stack) for more than 840 hours in any consecutive 12-month period.

Table 4, Item 11:

For coal burning devices placed in operation before April 15, 1970, the sulfur content of the coal shall not exceed 2.8 pounds per million BTU gross heat content at any time. [Note: This condition is already contained in an existing permit for Units MK1 and MK2 but was included for further clarification].

Table 4, Item 12:

For coal burning devices placed in operation before April 15, 1970, the sulfur content of the coal shall not exceed 2.0 pounds per million BTU gross heat content averaged over any consecutive 3-month period. [Note: This condition is already contained in an existing permit for Units MK1 and MK2 but was included for further clarification].

Table 5, Item 2:

The Owner shall conduct an initial performance test for SO_2 to demonstrate compliance with the respective SO_2 emissions limitation in Table 4, Items 6 and 8. [Underlined text was added and this condition was also extended to apply to Unit MK1]

Table 6, Item 7:

The owner or operator shall use Method ASTM D 4239-00 to determine the sulfur content of coal in pounds of sulfur per million BTU gross heat content.

Table 7, Item 6:

The owner or operator shall maintain the following sulfur analysis records:

a. Records showing the maximum weight percentage sulfur and quantity of each fuel delivery shipment received; and

b. Records showing either:

  1. The analytical method used and the specified fuel analysis results of the shipment or consignment from which the shipment came; or

  2. Delivery records sufficient to allow for traceability of the analytical results corresponding to each shipment received by the stationary source, showing:
     i. The date of delivery;
     ii. The quantity of delivery;
     iii. The type of fuel;
     iv. The maximum weight percentage sulfur; and

v. The name, address, and telephone number of the company making the delivery.

Table 8, Item 5:

Quarterly Coal Report

The Owner shall submit to DES no later than 30 calendar days after the end of the calendar quarter, the information required in Table 7, Item 6. Submittal of the "Monthly Report of Cost and Quality of Fuel for Electric Plants," will satisfy the requirements of this condition.

7. Comments Regarding Alternative Operating Scenarios

A comment was received regarding five operating scenarios as discussed in the Permit Application Review Summary document supporting the draft Temporary Permit. For clarification, the five operating scenarios are provided below.

- Units MK1 and MK2 exhausting through stack STMK3 (new FGD stack);
- MK1 exhausting through stack STMK3; MK2 not operating;
- MK1 exhausting through stack STMK2 (existing MK2 stack); MK2 not operating;
- MK2 exhausting through stack STMK3; MK1 not operating; and
- MK1 exhausting through stack STMK2 and MK2 exhausting through stack STMK3.

The proposed "normal" operating scenario will be for Units MK1 and MK2 to be firing coal at 100% load and exhausting through the new FGD scrubber stack (STMK3). The other scenarios address certain situations where the FGD system is offline as part of scheduled maintenance outages or if an unforeseen circumstance requires shutdown of the FGD system. DES notes that all five scenarios listed above result in lower emissions and lower ambient air quality impacts when compared to the current operating scenario for Units MK1 and MK2. In addition, under no scenario does Unit MK2, the larger unit, operate without the FGD system in operation to maximize the amount of mercury reduced.

The commenter states that the permit application does not address any alternative operating scenarios beyond installation of the FGD system. The commenter also claims that the application does not provide any data regarding the emissions, rate or mass, which would result from each of the five proposed operating scenarios. They further comment that the application does not provide any of the physical changes that will be made to facilitate the proposed operating scenarios and does not provide any applicable requirements for these scenarios. The commenter concludes that "the draft Temporary Permit is deficient in its failure to provide applicable requirements applicable to alternative operating scenarios."

DES Response:

The proposed operating scenarios are sufficiently described in the permit application. The portion of the application titled "*Air Quality Modeling Report*", specifically, Section 2.2 of the report titled "*Source Parameters*" provides very specific data regarding the emissions rates and source characteristics for each of the five proposed operating scenarios and the assumptions used by the applicant. DES also required the evaluation of each of these operating scenarios under various operating load conditions, as an additional measure to ensure that "worst-case" impacts are fully evaluated. Section 3.3 of the modeling report contains tables for each operating scenario, which list the maximum predicted ambient air concentrations for each pollutant evaluated. These evaluations were also discussed in detail in the DES Application Review Summary that supports the draft Temporary Permit.

The draft Temporary Permit <u>does</u> contain requirements applicable to the five operating scenarios, under Table 6, Item 1 of the permit. Further, the application and supporting information provide sufficient detail and applicable requirements to allow the various operating scenarios. Nevertheless, DES established additional requirements in the Temporary Permit to further clarify these limitations, including limitations applicable to Unit MK1.

8. Comments Regarding Procedural Issues on DES' Review of the Permit Application

<u>Comment that application was incomplete:</u>

DES received a comment that the applicant did not provide the information required by Env-A 607.03(d), which specifies that a major source must submit all information specified in Env-A 1709, *Information Required for Title V Sources*. The commenter specifically mentioned that the following information was not provided:

> "A citation and description of state and federal air pollution control regulations and requirements applicable to each unit (Env-A 1709.01(c));
>
> Any additional information required to be provided pursuant to the Act or to determine applicability of any other requirements of the Act (Env-A 1709(e));
>
> A narrative description of the compliance status of the source with respect to all applicable requirements (Env-A 1709(h)(1));
>
> A narrative statement of methods used to determine continued compliance, including a description of monitoring, recordkeeping and reporting requirements and test methods (Env-A 1709(h))."

<u>DES response:</u>

In an effort to streamline 40 CFR Part 70 permit applications (Title V Operating Permit applications), EPA issued two White Papers providing guidance to permitting authorities on various issues including the content of applications. Although this application is not a Title V Operating Permit application, the citations referenced by the commenter relate to requirements for Title V subject facilities and are consistent with requirements for Title V Operating Permit applications. Specifically, *White Paper for Streamlined Development of Part 70 Permit Applications* (White Paper #1), dated July 10, 1995, provides several streamlining improvements including certifying compliance status without requiring re-consideration of previous applicability decisions. White Paper #1 grants a substantial degree of discretion to State permitting agencies and encourages agencies to keep application requirements to a minimum to reduce redundancy and regulatory burdens.

Based on this guidance and the information contained both in the application and information required to be submitted in accordance with Part 70 requirements, the applicant submitted all of the information required by Env-A 607.03(d). As a general rule of business, DES allows all applicable stationary sources the use of additional information/reports filed in accordance with other regulations (for instance, annual compliance certifications) for purposes of fulfilling the regulatory requirements specified in Env-A 607.03(d). This approach is consistent with the Department's and EPA's philosophy to reduce redundancy and burdens associated with application submittal. The applicant submitted an initial temporary permit application by the statutory deadline of June 8, 2007, and submitted additional information on September 4, 2007, April 17, 2008, October 24, 2008, November 21, 2008 and December 11, 2008, to supplement the initial application, including the following:

- A draft and final air quality modeling protocol;
- An air quality modeling report;
- Conceptual design drawings showing the general arrangement of the FGD system;
- Updated emissions data; and
- The annual Title V compliance certification.

In addition, all of the information contained in Env-A 607.03(d) is contained in the facility's Title V Operating Permit application which is currently under review by DES. The status of this application review is discussed later in this document. The facility's Title V permit application contains all applicable requirements for the Merrimack Station facility. Consistent with White Paper #1, DES did not see the need to require that this information be submitted in duplicate.

Comments regarding lack of completeness determination:

DES received comments that DES could not and did not follow the statutory and regulatory procedures to deem the application complete since the application was "lacking substantial amounts of required information."

DES response:

The applicant submitted an initial temporary permit application by the statutory deadline of June 8, 2007. DES reviewed the initial application and identified deficiencies and responded to PSNH with a letter of incompleteness in accordance with Env-A 607.05, *Acknowledgment and Completeness of Application,* dated August 6, 2007. The provisions of Env-A 607.05 read:

> "Pursuant to RSA 541-A:29,I, within 60 days of receipt of an application, the department shall notify the applicant that said application is deemed complete or shall request that the applicant submit information in accordance with Env-A 607.03(b)."

The intent of this provision is to ensure that DES receives adequate information and reviews the application in a timely manner. In the event that DES does not act timely on its review of the application and does not provide a response to the applicant within the 60 day period, the application becomes administratively complete by default. Likewise, if DES does complete a review and the applicant responds with the requested information in accordance with the schedule provided in the incompleteness notification letter, the application becomes complete by default regardless of a response by DES. The applicant responded with the requested information on August 6, 2007 and included a detailed schedule for additional information that would be submitted as part of the application. In terms of public participation, DES followed all necessary requirements to allow for public review of all the submitted information and provide adequate public notice and opportunity for the submission of written comments and public hearing.

Comment that DES did not follow the procedures for a complete application:

DES received a comment stating that, because DES did not receive a complete application, DES could not and did not follow the procedures for a complete application, including sending a copy to the town and providing a location to examine the application and pertinent information.

DES response:

Based on the discussion outlined above, DES disagrees with the commenter who stated that DES did not follow the procedures for a complete application. In compliance with Env-A 621.07, *Public Access to Information,* DES sent a copy of the application to the town of Bow on December 11, 2008. Further, the public notice, which was published in the *Concord Monitor* on December 11, 2008 and the *Union Leader* on December 12, 2008, stated that the information could be reviewed at the offices of DES at 29 Hazen Drive in Concord, New Hampshire during working hours from 8 a.m. to 4 p.m., Monday through Friday. In addition, all information, including all the submittals was available on the Department's website from the time that the public notice was issued.

Comment that DES issued draft permit before receiving all information:

DES received comments that DES rendered a decision on the draft temporary permit before receiving all information. The commenters noted that the draft permit and additional information were dated the same day.

DES response:

In reviewing the application materials and finalizing the engineering summary associated with the project, DES found an error in the initial application, and requested the applicant to revise the applicable information. The information received on December 11, 2008, was updated actual pound per hour emissions data for MK1 and MK2. The corrections were not necessary to determine the applicability of any rule or regulation; they were requested solely to ensure that the permit application was accurate. To the extent that any applicability determinations dictate the use of hourly emissions, potential hourly emissions were required to be used. In addition, the applicant provided actual emissions data for 2007, which were not available during the initial permit application submittal in June 2007. While the draft permit and the applicant's additional emission information were dated the same day, the hourly emissions data change had no impact with respect to any applicability determinations and associated regulatory requirements. Thus, the updated data did not change any decisions by DES.

Comment that the draft permit is inadequate:

A commenter stated that, because the application was not complete, "the draft permit is inadequate and does not meet the requirements of Env-A 607.04, *Department Review of Applications*." The commenter states the following:

> "The permit does not quantify the increase (and/or change) in emissions that will result from the proposed modification(s), does not provide the pre-change mass emissions, does not provide the post-change mass emissions and does not impose annual mass emission limits necessary to implement all applicable requirements."

DES response:

The permit authorizes the installation of new control technology that is expected to significantly reduce mercury and SO_2 emissions. The application provides the pre-change emissions, and the permit establishes testing requirements to determine the post-change emissions. If this project required a NSR permit as a major modification, some of the items listed above would need to be specified in the permit. However, DES determined that this project is not a major modification under the NSR program, as explained in the section titled *Comments Regarding Federal New Source Review Program Requirements*. While emissions increases/changes are evaluated as part of the application review process, and in some cases additional permit limits are necessary to implement all applicable requirements, they are not always required in a permit.

Based on all of the information submitted by the applicant and DES's review thereof, DES has determined that the requirements of Env-A 607.04 have been met.

9. Comments Related to Title V Permit

Comments were received noting that the facility has yet to obtain a Title V Operating Permit from DES. The commenters claim that a Title V Operating Permit must be in place to ensure proper data collection and that a Title V Operating Permit should be issued before the applicant obtains a Temporary Permit for the FGD project.

DES Response:

DES notes that comments related to the Title V Operating Permit program are outside the scope of this permit proceeding, as they do not raise a material issue of fact with respect to any specific condition of the draft Temporary Permit. However, due to the number of comments regarding the Title V Operating Permit, it is appropriate to provide an explanation of the Title V Operating Permit program and how it relates to Merrimack Station.

PSNH Merrimack Station is one of New Hampshire's 46 stationary sources subject to NH's Title V Operating Permit Program (codified in 40 CFR Part 70 and Env-A 609, *Title V*

Operating Permits). Since the 1970s, PSNH has been required to obtain permits with the Department's Air Resources Division. When the Clean Air Act Amendments of 1990 became effective, New Hampshire established rules (Env-A 609) consistent with federal regulations (40 CFR Part 70). In accordance with these regulations, applicable sources were required to file an application with DES by July 1, 1996. PSNH filed a complete Title V Operating Permit application on July 1, 1996. In accordance with state regulations, Env-A 609.08, *Application Shield*, PSNH was granted application shield. The application shield provisions are stated below:

(a) If an applicant submits a timely and complete application for the issuance or renewal of a title V operating permit, the failure to have a title v operating permit shall not be considered a violation of this part unless and until the department take final action on the application by denying the requested permit.
(b) The protection granted in (a), above shall cease to apply if the applicant fails to submit in writing any information requested by the department pursuant to Env-A 609.12, by the deadline specified.

These provisions allow an affected source to continue operations in accordance with existing state operating permits (including expired state operating permits) until such time as the DES makes a final decision on the Title V Operating Permit application. PSNH Merrimack Station currently operates under nine State Operating Permits (Unit MK1, Unit MK 2, Combustion Turbine #1, Combustion Turbine #2, Primary Coal Crusher, Secondary Coal Crusher, Temporary Emergency Boiler, Emergency Generator and the Acid Rain Permit). PSNH Merrimack Station also operates under a NOx RACT Order for compliance with Env-A 1211, *Oxides of Nitrogen (NOx).*

As stated in the preamble of the Title V Operating Permit regulations (40 CFR Part 70), the Title V Permit Program **does not** impose substantive new requirements on sources subject to these regulations. The intent of this program is to establish a clearing house (one document) to clarify all applicable requirements. PSNH must meet all applicable requirements whether the source has been issued a Title V Operating Permit or not. Neither Env-A 609 **nor** 40 CFR Part 70 requires any additional emissions reductions and/or substantive requirements that the applicant isn't already required to meet. Currently, the facility must meet all of the conditions of its existing permits and any additional requirements that became effective during the permit terms. It must pay fees associated with New Hampshire's Title V Operating Permit program and must submit all necessary reports applicable to Title V sources (including the semi-annual permit deviation and monitoring report and the annual compliance certification report.)

Most states, including New Hampshire, maintain separate construction and operating permit programs (such as the Title V Operating Permit Program). Therefore, the introduction of any new substantive applicable requirements to any Title V subject facility must be administered through the state's construction permit program referred as a Temporary Permit in New Hampshire. A source must obtain approval under the state's Temporary Permit Program and/or applicable federal New Source Review regulations for any new applicable requirements including requirements associated with modifications made at Title V facilities. At the present time, DES' permitting efforts relative to PSNH Merrimack Station are focused on the review of a construction permit application for the mercury scrubber project as required under RSA 125-O.

While DES recognizes the benefits of the Title V Operating Permit Program and the need for issuance of the Title V Operating Permit for PSNH Merrimack Station, by not having a Title V Operating Permit at this time, PSNH is not permitted any additional environmental or financial benefits of continued operation. DES has made substantial progress in reviewing the Title V Operating Permit application for this facility. However, due to various legislative and rulemaking emission reduction efforts, and pollution control projects at this facility (as well as applications for new construction at other New Hampshire facilities), DES has not finalized its review of the Title V Operating Permit application in order to dedicate resources to these environmentally beneficial efforts. The review of the facility's Title V Operating permit application is well underway and once a final decision related to the mercury scrubber project is complete, staff resources will be rededicated to finalizing the review of the Title V Operating permit application for this facility.

Findings of Fact

In order to comply with state and federal regulations, PSNH is proposing to install and operate a flue gas desulphurization (FGD) system. With the installation of the proposed control equipment, emissions of mercury and sulfur dioxide will be further reduced, and visibility will be improved.

In response to the application for a Temporary Permit, DES conducted a comprehensive review of the proposed project. In addition, DES considered comments provided during the public hearing and in writing to DES during the public comment period. Based on its review, DES determined that the applicant meets all state and federal air regulations including the National Ambient Air Quality Standards for criteria pollutants and the New Hampshire Ambient Air Limits for all regulated toxic air pollutants. This determination was based on emissions rates established for the existing operation as well as the proposed operation with the installation of the above mentioned FGD system.

In order to ensure compliance with all applicable requirements, various monitoring conditions have been included in the Temporary Permit. These include requirements for continuous emissions monitors, periodic compliance stack tests and monitoring of operational parameters.

In summary, after consideration of comments received during the public comment period, DES has made the following additions/revisions (excluding minor changes to correct any typographical errors) to the draft Temporary Permit.

Table 4, Item 6:

a. Beginning on July 1, 2013, when MK2-PC7 (FGD system) is in operation, SO_2 emissions shall be controlled to 10 percent of the uncontrolled SO_2 emission rate (90 percent SO_2 removal). Compliance with this percent reduction shall be determined on a calendar month average by comparing the SO_2 emission rates as measured by CEMS on the inlet and outlet of the FGD system.

b. The Owner shall submit a report no later than December 31, 2014 that includes the calendar month average SO_2 emission rates at the inlet and outlet of the FGD and the corresponding calendar month average emissions reductions during the preceding 12 months of operation, excluding the initial startup and commissioning period and any periods when the FGD system is not operating. DES will use this data to establish the maximum sustainable rate of SO_2 emissions reductions for MK2. The maximum sustainable rate is the highest rate of reductions that can be achieved 100 percent of the time.

c. DES shall establish the maximum sustainable rate of SO_2 emissions reductions based on a statistical analysis of the data submitted to DES pursuant to paragraph b. above. This established rate shall be incorporated as a permit condition for MK2. Under no circumstances shall the SO_2 removal efficiency for MK2 be less than 90 percent.

<u>Table 4, Item 8</u>:

a. Beginning on July 1, 2013, when MK2-PC7 (FGD system) is in operation, SO_2 emissions shall be controlled to 10 percent of the uncontrolled SO_2 emission rate (90 percent SO_2 removal). Compliance with this percent reduction shall be determined on a calendar month average by comparing the SO_2 emission rates as measured by CEMS on the inlet and outlet of the FGD system.

b. The owner shall submit a report no later than December 31, 2014 that includes the calendar month average SO_2 emission rates at the inlet and outlet of the FGD and the corresponding calendar month average emissions reductions during the preceding 12 months of operation, excluding the initial startup and commissioning period and any periods when the FGD system is not operating. DES will use this data to establish the maximum sustainable rate of SO_2 emissions reductions for MK1. The maximum sustainable rate is the highest rate of reductions that can be achieved 100 percent of the time.

c. DES shall establish the maximum sustainable rate of SO_2 emissions reductions based on a statistical analysis of the data submitted to DES pursuant to paragraph b. above. This established rate shall be incorporated as a permit condition for MK1. Under no circumstances shall the SO_2 removal efficiency for MK1 be less than 90 percent.

<u>Table 4, Item 9</u>:

Beginning on July 1, 2013, the Owner shall not operate MK1 through STMK2 (bypass stack) if MK2-PC7 is capable of stable operation.

<u>Table 4, Item 10</u>:

Beginning on July 1, 2013, the Owner shall not operate MK1 through STMK2 (bypass stack) for more than 840 hours in any consecutive 12-month period.

<u>Table 4, Item 11</u>:

For coal burning devices placed in operation before April 15, 1970, the sulfur content of the coal shall not exceed 2.8 pounds per million BTU gross heat content at any time. [<u>Note</u>: This condition is already contained in an existing permit for Units MK1 and MK2 but was included for further clarification].

<u>Table 4, Item 12</u>:

For coal burning devices placed in operation before April 15, 1970, the sulfur content of the coal shall not exceed 2.0 pounds per million BTU gross heat content averaged over any consecutive 3-month period. [<u>Note</u>: This condition is already contained in an existing permit for Units MK1 and MK2 but was included for further clarification].

<u>Table 5, Item 2</u>:

The Owner shall conduct an initial performance test for SO_2 to demonstrate compliance with the respective SO_2 emissions limitation in Table 4, Items 6 <u>and 8</u>. [Underlined text was added and this condition was also extended to apply to Unit MK1]

<u>Table 6, Item 7</u>:

The owner or operator shall use Method ASTM D 4239-00 to determine the sulfur content of coal in pounds of sulfur per million BTU gross heat content.

<u>Table 7, Item 6</u>:

The owner or operator shall maintain the following sulfur analysis records:

a. Records showing the maximum weight percentage sulfur and quantity of each fuel delivery shipment received; and

b. Records showing either:

   1. The analytical method used and the specified fuel analysis results of the shipment or consignment from which the shipment came; or

   2. Delivery records sufficient to allow for traceability of the analytical results corresponding to each shipment received by the stationary source, showing:

      i. The date of delivery;
      ii. The quantity of delivery;
      iii. The type of fuel;
      vi. The maximum weight percentage sulfur; and
      vii. The name, address, and telephone number of the company making the delivery.

<u>Table 8, Item 5</u>:

Quarterly Coal Report

The Owner shall submit to DES no later than 30 calendar days after the end of the calendar quarter, the information required in Table 7, Item 6. Submittal of the "Monthly Report of Cost and Quality of Fuel for Electric Plants," will satisfy the requirements of this condition.

<u>Director's Decision</u>

After consideration of the Temporary Permit Application, supplements thereto, and all public comments, the application is approved subject to the revisions to the draft permit noted above, and a final Temporary Permit is hereby issued.

Pursuant to RSA 125-C:12, III and Env-A 621.10, *Appeals*, any person aggrieved by this decision may file a petition for appeal with the Air Resources Council which shall be received within 10 days of the date below. Such appeal and 15 copies shall be filed in accordance with the provisions of Env-AC 200, *Procedural Rules* and forwarded to the Chair of the Air Resources Council at the address below:

Chair of the Air Resources Council
c/o DES, Air Resources Division
29 Hazen Drive, P.O. Box 95
Concord, NH 03302-0095
ATTN: ARC Clerk

COPY

Robert R. Scott
Director
Air Resources Division

March 9, 2009
Date

cc: Town of Bow
Public Hearing Attendees/Public Commenters
David B. Conroy, EPA Region I